

**TESTIMONY OF  
JERYL L. MOHN  
SENIOR VICE PRESIDENT, OPERATIONS & ENGINEERING  
PANHANDLE ENERGY**

**ON BEHALF OF THE  
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA**

**BEFORE THE  
SUBCOMMITTEE ON ENERGY AND AIR QUALITY  
COMMITTEE ON ENERGY AND COMMERCE  
U.S. HOUSE OF REPRESENTATIVES**

**REGARDING THE  
REAUTHORIZATION OF THE PIPELINE SAFETY ACT**

**APRIL 27<sup>TH</sup>, 2006**

Mr. Chairman and Members of the Subcommittee:

Good morning. My name is Jeryl Mohn, and I am Senior Vice President of Operations and Engineering for Panhandle Energy. I am testifying today on behalf of the Interstate Natural Gas Association of America (INGAA). INGAA represents the interstate and interprovincial natural gas pipeline industry in North America. INGAA's members transport over 90 percent of the natural gas consumed in the United States through a network of approximately 200,000 miles of transmission pipeline. These transmission pipelines are analogous to the interstate highway system – in other words, large capacity systems spanning multiple states or regions.

Panhandle Energy, headquartered in Houston, Texas, is a subsidiary of the Southern Union Company and owns or holds a major ownership interest in five interstate pipelines and a liquefied natural gas import terminal. Our pipelines serve a significant share of the markets in the Midwest, the Southwest including California, and Florida. In addition, our Trunkline LNG terminal in Lake Charles, Louisiana is one of the nation's largest LNG import facilities.

## **INDUSTRY BACKGROUND**

Mr. Chairman, natural gas provides 25 percent of the energy consumed in the U.S. annually, second only to petroleum and exceeding that of coal or nuclear. From home heating and cooking, to industrial processes, to power generation, natural gas is a versatile and strategically important energy resource.

As a result of the regulatory restructuring of the industry during the 1980s and early 1990s, interstate natural gas pipelines no longer buy or sell natural gas. Interstate pipelines do not take title to the natural gas moving through our pipelines. Instead, pipeline companies sell transportation capacity in much the same way as a railroad, airline or trucking company.

Because the natural gas pipeline network is essentially a "just-in-time" delivery system, with limited storage capacity, customers large and small depend on reliable around-the-clock service. That is an important reason why the safe and reliable operation of our pipeline systems is so important. The natural gas transmission pipelines operated by INGAA's members and by others historically have been the safest mode of transportation in the United States. The interstate pipeline industry, working cooperatively with the Pipeline and Hazardous Materials Safety Administration (PHMSA), is taking affirmative steps to make this valuable infrastructure even safer.

Congressional involvement in pipeline safety dates back almost 40 years to enactment of the Natural Gas Pipeline Safety Act in 1968. This legislation borrowed heavily from the engineering standards that had been developed over the previous decades. The goals of this federal legislation were to ensure the consistent use of best practices for pipeline safety practices across the entire industry, to encourage continual improvement in safety procedures and to verify compliance. While subsequent reauthorization bills have

improved upon the original, the core objectives of the federal pipeline safety law have remained a constant.

## **HOW SAFE ARE NATURAL GAS PIPELINES**

While the safety record of natural gas transmission lines is not perfect, it nonetheless compares very well to other modes of transportation. Since natural gas pipelines are buried and isolated from the public, pipeline accidents involving fatalities and injuries are unusual.

In 2005 there were no fatalities and 5 injuries associated with our pipelines. During the period 2002 -2005, there were a total of two fatalities and 21 injuries. Both fatalities and nine of the injuries were attributable to excavation damage or vehicular crashes with pipeline facilities. The remainder of the injuries involved pipeline company repair/maintenance personnel.

There are rare exceptions to the exceptional safety record of natural gas transmission pipelines. The accident that occurred near Carlsbad, New Mexico in 2000 resulted in the deaths of 12 family members who were camping on a remote pipeline right-of-way. That accident was the result of internal corrosion on a section of pipe that could not be inspected by internal inspection devices due to engineering constraints (more on that issue below). This has been the only gas transmission corrosion incident with fatalities since 1985, when PHMSA improved its record keeping system.

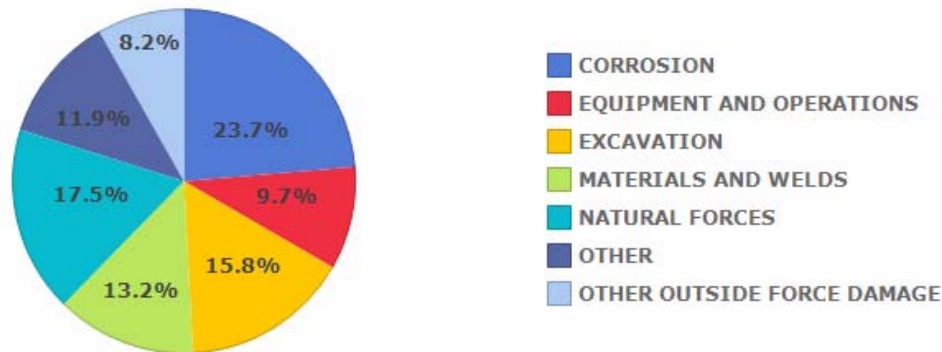
Since 1984, the Department of Transportation has defined a “reportable incident” as one that results in a fatality, an injury, or property damage exceeding \$50,000. Included in the determination of property damage, however, is damage to the pipeline itself and the *monetary value of the natural gas lost*. As most of you know, natural gas commodity prices have increased more than 300 percent in the last six years. This linkage of “reportable incidents” to natural gas commodity prices has resulted in heavily skewed data over the last several years.

Internally, PHMSA has discussed a new “serious accident” incident category, which includes incidents with fatalities, injuries and fires. This category would rely less on the amount of natural gas lost to the air and would be, therefore, a more effective measure of safety performance. Another alternative would be a volumetric threshold for natural gas lost based on 2002 natural gas prices. If the 2005 incident data was normalized to 2002 gas prices, for example, 60 fewer onshore incidents would have been reported. Either approach would provide more consistency in the reportable incident data and help focus industry and PHMSA efforts on the more serious issues of human safety.

In terms of the causes of accidents on gas transmission pipelines, the table below shows that corrosion (internal and external) accounts for about one quarter of all incidents. This statistic is important, because the periodic inspection aspects of the Integrity Management Program discussed later are principally designed to reduce the risk of corrosion-related failures in highly populated areas. “Natural forces” was the second leading cause of

damage, with the Gulf Hurricanes Ivan, Katrina and Rita accounting for most of these incidents. “Excavation damage,” which tends to be the leading cause of fatalities associated with natural gas transmission lines, is the third leading cause of incidents. The new PHMSA accident statistics separate excavation damage from “other outside force damage” – most of the incidents associated with this new category are the result of vehicular crashes with pipeline facilities.

#### **Natural Gas Transmission Failure Causes 2002-2005**



*Source: OPS FOIA Library Files March 08,2006*

#### **THE PIPELINE SAFETY IMPROVEMENT ACT OF 2002 AND INTEGRITY MANAGEMENT**

The most recent reauthorization bill – the Pipeline Safety Improvement Act of 2002 (“PSIA”) – focused on a variety of issues, including operator qualification programs, public education, and population encroachment on pipeline rights-of-way. But the most significant provision of the 2002 law that will improve long-term pipeline safety dealt with the “Integrity Management Program” (“IMP”) for natural gas transmission pipelines.

Section 14 of the PSIA requires operators of natural gas transmission pipelines to: 1) identify all the segments of their pipelines located in “high consequence areas” (areas adjacent to significant population); 2) develop an integrity management program to reduce the risks to the public in these high consequence areas; 3) undertake baseline integrity assessments (inspections) at all pipeline segments located in high consequence areas, to be completed within 10 years of enactment; 4) develop a process for making repairs to any anomalies found as a result of these inspections; and 5) reassess these segments of pipeline every 7 years thereafter, in order to verify continued pipe integrity.

The PSIA requires that these integrity inspections be performed by one of the following methods: 1) an internal inspection device (or a “smart pig”); 2) hydrostatic pressure testing (filling the pipe up with water and pressurizing it well above operating pressures

to verify a safety margin); 3) direct assessment (digging up and visually inspecting sections of pipe), or 4) “other alternative methods that the Secretary of Transportation determines would provide an equal or greater level of safety.” The pipeline operator is then required by regulations implementing the 2002 law to repair all non-innocuous imperfections and adjust operation and maintenance practices to minimize “reportable incidents”. For natural gas transmission pipelines, internal inspection devices are the primary means of integrity assessments, due to the fact that, when they can be used, they are more versatile and efficient. Other assessment alternatives listed in the legislation are useful in cases where smart pig technology cannot be effectively used. A drawback associated with such alternatives is that they require a pipeline to cease or significantly curtail gas delivery operations for periods of time.

In-line internal inspection “smart pig” devices were invented by the natural gas pipeline industry several decades ago, and over the years their capabilities and effectiveness as analytical tools have increased. Still, the pipeline industry must address some practical issues our industry must deal with in order to utilize these devices more fully.

First, our older pipelines were not engineered to accept such inspection devices. This means that older pipelines were often built with tight pipe bends, non-full pipe diameter valves, continuous sections of pipe with varying diameters, and side lateral piping. In all of these circumstances, the movement of natural gas is not impeded because of its relative compressibility. Moving a solid object through such pipelines is another matter, however. These older pipeline systems must be modified to allow the use of internal inspection devices.

The other legacy issue is the modification of pipelines to launch and receive internal inspection devices. Since a pipeline is buried underground for virtually its entire length, the installation of aboveground pig launchers and receivers is usually done at or near other above ground locations such as compressor stations. Occasionally, however, new sites must be obtained for these facilities. Compressor stations are typically located along the pipeline at a spacing of 75 to 100 miles apart. Therefore, for every segment, another set of launchers and receivers needs to be installed. Once installed, these launchers and receivers can usually remain in place permanently.

Surveys conducted by our industry about five years ago suggested that almost one-third of transmission pipeline mileage could immediately accommodate smart pigs, another one-quarter could accommodate smart pigs with the addition of permanent or temporary launching and receiving facilities, and the remainder, about 40-45 percent, would either require extensive modifications or never be able to accommodate smart pigs due to the physical or operational characteristics of the pipeline. Scheduling these extensive modifications to minimize consumer delivery impacts has been one of the most challenging aspects of the Integrity Management Program.

The natural gas pipeline industry will use hydrostatic pressure testing and direct assessment for segments of transmission pipeline that cannot be modified to accommodate smart pigs, or in other special circumstances. There are issues worth

noting with both hydrostatic testing and direct assessment. In the case of hydrostatic testing, an entire section of pipeline must be taken out of service for an extended period of time, limiting the ability to deliver gas to downstream customers and potentially causing market disruptions as a result. In addition, hydrostatic testing – filling a pipeline up with water at great pressure to see if the pipe fails – is a destructive or “go – no go” testing method that must take into account pipeline characteristics so that it does not exacerbate some conditions while resolving others. Also, because of this “go – no go” nature, testing must continue until the segment successfully completes the test, generally 8 hours at pressure, with no leaks or failures.

Direct assessment is generally defined as an inspection method whereby statistically chosen sections of pipe are excavated and visually inspected at certain distance intervals along the pipeline right-of-way based on sophisticated above ground electrical survey measurements that predict problem areas. The amount of excavation and subsequent disturbance of landowner’s property involved with this technology is significant and does not decrease with future reassessments. Disturbing other infrastructures, including roads and other utilities, is also a significant risk and inconvenience for the public.

One final note. While the pipeline modifications and inspection activity can generally follow a pre-arranged schedule, repair work is an unpredictable factor. A pipeline operator does not know, ahead of time, how many anomalies an inspection will find, how severe such anomalies will be, and how quickly they will need to be repaired. Only the completed inspection data can provide that information. Repair work often requires systems to be shut down, even if the original inspection work did not affect system operations. The unpredictable nature of repair work must be kept in mind, especially during the baseline inspection period, when we can expect the number of required repairs to be the greatest.

## **INTEGRITY MANAGEMENT PROGRESS TO DATE**

The integrity management program mandated by the PSIA is performing very well. The program is doing what Congress intended; that is, verifying the safety of gas transmission pipelines located in populated areas and identifying and removing potential problems before they occur. Based on two years of data, the trend is that our pipelines are safe and are becoming safer.

PHMSA immediately initiated a rulemaking to implement the gas integrity requirements upon enactment of PSIA in December of 2002. The Administration successfully met the one-year deadline set by the law for issuing a final IMP rule. Therefore, 2004 was the first full year of what will end up being a nine-year baseline testing period (the statute mandates that baseline tests on all pipeline segments in high consequence areas must be completed by December of 2012). PHMSA’s final rule credits pipeline companies for some integrity assessments completed before the rule took effect, thereby mitigating the effects of the shorter baseline period.

PHMSA has reported on progress achieved thus far:

1. Total Gas Transmission Mileage in the United States – There are 295,665 miles of gas transmission pipeline in the U.S. INGAA's members own approximately 200,000 miles of this total, with the remainder being owned by *intrastate* transmission systems or local distribution companies.
2. Total High Consequence Area (HCA) Mileage – There are 20,191 miles of pipeline in HCAs (i.e., mileage subject to gas integrity rule). This represents about 7 percent of total mileage.
3. HCA Pipeline Miles Inspected to Date –
  - 2004 – 3,979 miles (incorporated some prior inspections before rule took effect).
  - 2005 – 2,744 miles
  - Therefore, 6,723 miles of HCA pipeline inspected to date, or 33 percent of total.
4. Total Pipeline Miles Inspected (including non-HCA pipeline) –
  - 2004 – 30,452 miles (7.65 to 1 over-test ratio)
  - 2005 – 19,884 miles (7.24 to 1 over-test ratio)
  - Therefore, 50,366 total miles, or approximately 17 percent of total transmission pipeline mileage.

The total HCA pipeline mileage inspected to date suggests that the industry is generally on track with respect to meeting the 10-year baseline requirement. With three years of the baseline period completed at the end of 2005, about 30 percent of the HCA mileage had been inspected. This translates into 10 percent being completed annually – exactly the volume of work needed in order to meet the baseline requirement.

The 2002 law also required a risk-based prioritization of these HCA assessments, so that the higher-ranking HCA pipeline segments would be scheduled for assessment within five years of enactment. This means that by December of 2007 we must have completed at least half of the total HCA assessments, by mileage, and that work contains the segments with the highest probability of failure. Again, we appear to be on track for meeting this requirement.

The mileage counted as being assessed in 2004 is higher than what we anticipate will be the average annual mileage going forward, because we were able to include some HCA segments that had been inspected in the few years immediately prior to the rule taking effect. As mentioned, this helped to jump-start the program and make up for the fact that the final IMP rule did not take effect until December of 2003, thus reducing the *de facto* baseline period to nine years.

The vast majority of the assessments to date have been completed using smart pig devices. As discussed, these devices can only operate across large segments of pipeline – typically between two compressor stations. A 100 mile segment of pipeline may, for example, only contain 5 miles of HCA, but in order to assess that 5 miles of HCA, the entire 100 mile segment between compressor stations must be assessed. This dynamic is

resulting in a large amount of “over-testing” on our systems. While we have completed assessments on 6,723 miles of HCA pipe thus far, the industry has actually inspected about 50,366 miles of pipe in order to capture the HCA segments. Any problems that are identified as a result of inspections, whether in an HCA or not, are repaired.

As you can see from the data, only about 7 percent of total gas transmission pipeline mileage is located in HCAs. Yet, due to the over-testing situation, we anticipate that about 55 to 60 percent of total transmission mileage will actually be inspected during the baseline period.

Now let us look at what the integrity inspections have found to date. For this data, we focus on information from HCA segments, since these segments are the only ones specifically covered under the integrity management program.

1. Reportable Incidents in HCAs (in 20,191 miles)
  - 2004 – 9 (2 time-dependent)
  - 2005 – 10 (0 time-dependent)
2. Leaks (too small to be classified as a reportable incident) in HCAs (in 20,191 miles)
  - 2004 – 117 (29 time-dependent)
  - 2005 – 104 (20 time-dependent)
3. Immediate Repairs in HCAs Found by Inspections (repair within 5 days)
  - 2004 – 101 (3,979 miles inspected)
  - 2005 – 237 (2,744 miles inspected)
4. Scheduled Repairs in HCAs Found by Inspections (repair generally within 1 year)
  - 2004 – 595 (3,979 miles inspected)
  - 2005 – 403 (2,744 miles inspected)

In the data for incidents and leaks, we separate out the time-dependent defects, since these are the types of defects that are the prime target of reassessment under the integrity management program. By time-dependent, we mean problems with the pipeline that develop and grow over time, and, therefore, should be examined on a periodic time basis. The most prevalent time-dependent defect is corrosion; therefore, the IMP effort is focused most intently on corrosion identification and mitigation. These same assessments might also be able to identify other pipeline defects such as original construction defects or excavation damage. Original construction defects are usually found and addressed during post-construction inspections; any construction defects found with this new, more sensitive inspection technology would be fixed “for good” so that future assessments looking for these types of anomalies will be unnecessary. Most reportable incidents caused by excavation damage (more than 85 percent) result in an immediate pipeline failure, so periodic assessments are not likely to reduce the number of these types of accidents in any significant way. Periodic assessments on a fixed schedule are, therefore, most effective for time-dependent defects.

You can see that the number of incidents associated with time-dependent defects in HCA areas is fairly low and that these reportable incidents (e.g. 1 reportable incident per year



average) have occurred in HCA areas not yet assessed under this program. As critical time dependent defects are found and repaired, we expect these incident and leak numbers to approach zero, since the gestation period for these defects is significantly longer than the re-assessment interval.

As for repairs, we have identified the number of “immediate” and “scheduled” repairs that have been generated by the IMP inspections thus far. These are anomalies in pipelines that have not resulted in a reportable incident or leak, but are repaired as a precautionary measure. “Immediate repairs” and “scheduled repairs” are defined terms under both PHMSA regulations and engineering standards. As the name suggests, immediate repairs require immediate action by the operator, due to the higher probability of a reportable incident or leak in the future. Scheduled repair situations are those that require repair within a longer time period because of their lower probability of failure.

Even though we are early in the baseline assessment period, the data suggests a very positive conclusion regarding present state of the gas transmission pipeline system and the effectiveness of integrity management programs. “Immediate repairs” in HCAs removed 50 anomalies for every 1000 pipeline miles inspected. The number of “scheduled repairs” removed an additional 140 anomalies per 1000 miles inspected. By completing these immediate and scheduled repairs in a timely fashion, we are reducing the possibility of future reportable incidents or leaks. Also, data from operators who have completed more than one such periodic assessment over a number of years strongly suggests a dramatic decrease in the occurrence of time-dependent defects requiring repairs the second time around.

Many of the gas pipelines being inspected under this program are 50 to 60 years old. While it is often hard for non-engineers to accept, well-maintained pipelines can operate safely for many decades. Policymakers often compare pipelines to vehicles and ask questions such as: “Would you fly in a 50-year-old airplane?” The comparison to aircraft or automobiles is an unsound one, though, from an engineering standpoint. Natural gas pipelines are built to be robust and are not subject to the same operational stresses as vehicles. Much of the above inspection data comes from pipelines that were built in the 1940s and 1950s. And yet, the number of anomalies found on a per-mile basis is low. Once these anomalies are repaired, the “clock can be reset,” and these pipelines can operate safely and reliably for many additional decades. One important benefit of the integrity management program is the verification and re-certification of the safety on these older pipeline systems.

## **ISSUES FOR THE 2006 REAUTHORIZATION**

The 2002 Act authorized the federal pipeline safety program at the Department of Transportation through fiscal year 2006. Although the Congressional schedule for the rest of 2006 is short, the current program is working very effectively and therefore needs only modest changes. We therefore see no reason why Congress cannot reach consensus and complete a reauthorization bill this year. INGAA also urges the Congress to pass a

five-year reauthorization bill that would take the next reauthorization outside the short legislative calendar that occurs in an election year.

INGAA would like the Subcommittee to consider amendments addressing three issues in the pipeline safety law. Each of these would achieve an evolutionary change in the current pipeline safety program: 1) re-consideration of the seven-year reassessment interval, to one based instead upon a more reasoned approach; 2) improvements in state excavation damage prevention programs; and 3) change in the jurisdictional status for direct sales lateral lines.

### **Seven-Year Reassessment Interval**

Under the PSIA, gas transmission pipeline operators have 10 years in which to conduct baseline integrity assessments on all pipeline segments located in high consequence areas (HCAs). Operators are also required by law to begin reassessing previously-inspected pipe seven years after the initial baseline and every seven years thereafter. PHMSA has interpreted these two requirements to mean that, for those segments baseline-inspected in 2003 through 2005 (including those for which a prior assessment is relied upon), reassessments must be done in years 2010 through 2012 – *even though baseline inspections are still being conducted*.

In 2001 INGAA provided Congress with a proposed industry consensus standard on reassessment intervals that had been developed by the American Society of Mechanical Engineers (ASME). The ASME standard used several criteria to determine a reassessment interval for a particular segment of pipe, such as the operating pressure of a pipe relative to its strength and the type of inspection technique used. This standard relied upon authoritative technical analyses and a “decision matrix” based on more than 50 years of operational and performance data for gas pipelines.

For most natural gas transmission pipelines (operating at high pressures), the ASME standard proposed a conservative ten-year reassessment interval. The standard suggested longer inspection intervals for lower pressure lines, a small number of pipelines that are lower in risk due to their lower operating pressures. The standard also suggested shorter intervals for pipeline segments operating in higher-risk environments, including those where unusually aggressive corrosion would be more likely to occur. Recent and past pipeline inspection data confirms that the ASME criteria are conservative.

Why are we so concerned about the seven-year reassessment interval? First, there is the “overlap” in years 2010 through 2012. The ability to meet the required volume of inspections is daunting given the limited number of inspection contractors and equipment available. In addition, this stepped up level of inspection activity would be difficult to accommodate without affecting gas system deliverability. This last point is critical. Some assume that we are focusing on the re-assessment interval only because of the costs to industry. In fact, our costs will be modest compared to the potential costs to consumers in the form of higher natural gas commodity prices if pipeline capacity becomes too constrained. Some regions of the country can handle more frequent

reductions in pipeline deliverability, due to the volume of pipeline capacity serving those regions. The Chicago region and the Gulf Coast, for example, are equipped to handle frequent pipeline capacity interruptions due to the abundance of pipeline capacity in those regions. Other regions, such as the Northeast and Southern California, face greater risk that gas commodity prices will spike if pipeline capacity is reduced too often. These downstream market effects should be carefully considered, especially during the baseline inspection period when pipeline modifications (to accommodate inspection equipment), inspections, and repair work will all be at peak levels.

Some also suggest that if the pipeline industry is technically capable of inspecting its lines for corrosion more frequently than engineering standards suggest, then it should do so and not worry about the costs or the logistics. It is certainly true that large interstate pipelines could, in fact, be inspected more frequently than every seven years, especially once systems have been modified to accommodate smart pig devices. But just because pipelines can be inspected more often does not mean it is rational to require a one-size-fits-all inspection policy. Most automobile manufacturers recommend vehicle oil changes every 3000 miles. Congress could instead mandate that all vehicles have oil changes every 1000 miles, but, of course, there would be little, if any, additional benefit to the more frequent oil changes, and the costs associated with the more frequent oil changes would take money away from other, more beneficial maintenance activities.

The Integrity Management Program asks us to identify and mitigate risks to the public associated with operating our pipelines. Inspections are but one tool to achieve that end, and they do not accomplish all of the required goals of the program. The inspections carried out pursuant to the Integrity Management Program focus primarily on one cause of pipeline accidents – corrosion. Corrosion causes about 25 percent of the failures on gas transmission lines. What about the other 75 percent of accidents? What can be done to mitigate the risks of those? A credible and effective integrity management program prioritizes risks and develops strategies for addressing all risks. A program that mandates system-wide inspections too frequently can seriously affect an operator's ability to perform even more frequent inspections at the very few locations that may warrant shorter timeframes and may detract from other important integrity activities such as damage prevention.

We recognize that some lawmakers may be hesitant to change to the seven-year reassessment interval given the heated debate on this issue in 2002. This is especially true given that the Integrity Management Program is relatively new and that GAO has not finalized its final report. We still urge the Congress to address the reassessment issue in this reauthorization bill, particularly the inspection overlap. The inspection overlap issue will manifest itself within the next four years; in other words, during the next reauthorization period. Our industry has worked in good faith to make the IMP program work and to improve pipeline safety overall. We want this safety initiative to work, but we also want to continue doing our collective job to deliver natural gas supplies reliably across the country when those supplies are needed. INGAA has provided the GAO with data that clearly shows there would be no compromise of safety either by lengthening the seven-year interval or by eliminating the baseline-reassessment overlap.

## **Damage Prevention**

In 1998, the TEA21 highway legislation included a relatively modest program called the “One-Call Notification Act.” The goal of this legislation was to improve the quality and effectiveness of state one-call (or “call-before-you-dig”) damage prevention programs. By developing federal minimum standards and then giving grants to those states that adopted the minimum standards, this law contributed to improving damage prevention efforts all across the nation. And it did so without mandating that states adopt the federal minimum standards.

Over the last eight years, there has been a great deal of improvement in damage prevention. INGAA believes that the time has come to take these efforts to the next level. Excavation damage prevention has been, and should remain, a major focus for pipeline safety. On our gas transmission pipelines, accidental damage from excavation equipment is the leading cause of fatalities and injuries. The majority of incidents that have raised public and Congressional concern have been due to excavation damage. These accidents are the most preventable of all, and better communication between pipeline companies and excavators is the key to such accident prevention. Despite all the progress that has been made since 1998, some excavators still do not call before they dig.

One state, in particular, has developed an outstanding damage prevention program based on improved communication, information management, and performance monitoring. That state is Virginia. Not only does Virginia require broad participation by all utilities and excavators, but also it has effective public education programs and effective enforcement of its rules. We believe that enforcement is the most important element to improving state programs beyond the progress already made, and we believe Virginia offers a model for other states to adopt. Statistics demonstrate the success of the Virginia program – the state has experienced a 50 percent decrease in the excavation damage since implementing its program.

For 2006 we ask the Congress to emphasize once again the importance of excavation damage prevention by including a new program of incentives for state action. A modest amount of grant funds could go a long way in reducing accidents. INGAA would like to work with the American Gas Association and the Common Ground Alliance in proposing legislative language on this issue in the next few weeks.

## **Safety Regulation of Direct Sales Laterals**

One of the goals of the original Pipeline Safety Act enacted in 1968 was to establish a clear line of demarcation between federal and state authority to enforce pipeline safety regulations. Prior to 1968, many states had established their own safety requirements for interstate natural gas pipelines, and there was no particular consistency in such regulations across the states. This created compliance problems for interstate pipeline operators whose facilities crossed multiple states. The Pipeline Safety Act resolved this conflict by investing the U.S. Department of Transportation with exclusive jurisdiction

over interstate pipeline safety while delegating to the states authority to regulate intrastate pipeline systems (generally, pipelines whose facilities are wholly within a single state).

The statutory definition of an “interstate gas pipeline facility” subject to federal regulation was clarified further when the Congress reauthorized the Pipeline Safety Act in 1976 (P.L. 94-477). As part of this clarification, the Congress stated that “direct sales” lateral pipelines were not subject to federal jurisdiction. Direct sales laterals are typically smaller-diameter pipelines that connect a large-diameter interstate transmission pipeline to a single, large end-use customer, such as a power plant or a factory. Such direct sales laterals often are owned and maintained by the interstate transmission pipeline operator to which they are connected.

This clarification was made necessary by a 1972 U.S. Supreme Court decision (*Federal Power Commission v. Louisiana Power and Light*, 406 U.S. 621) in which the Court ruled that for purposes of economic regulation (*i.e.*, rate regulation), direct sales laterals were subject to preemptive federal jurisdiction. This ruling created uncertainty regarding the authority to regulate the safety of direct sales laterals because when the Pipeline Safety Act was enacted in 1968, it was assumed by the Congress that such pipelines would be subject to both economic and safety regulation at the state level.

While this exemption from federal jurisdiction may have made sense 30 years ago, it now is an anachronism. As mentioned, many of these direct sales laterals are owned and operated by interstate pipelines. The natural gas transported in such lines travels in interstate commerce, and the lateral lines are extensions of the interstate pipelines to which they are interconnected.

In addition, interstate natural gas pipelines are now subject to the PHMSA’s Gas Integrity Management Program and are required to undergo a specific regimen of Congressionally mandated inspections and safety verification. State-regulated pipelines are not covered under the federal program. Instead, states are allowed to create their own safety programs, which may have different processes/procedures covered than the federal integrity management program. Given the comprehensive federal program, there is no particular reason for small segments of the interstate pipeline system to be subject to differing and potentially inconsistent regulation at the state level. The inefficiency of this approach is further compounded by the fact that an interstate pipeline operator with direct sales laterals in multiple states likely will be subject to inconsistent regulation across the states. It is therefore understandable that interstate pipelines wish to have their direct sales laterals subject to the same federal integrity management requirements as mainline facilities. This would ensure a consistent and rational approach to integrity management system-wide, in contrast to being compelled to exclude parts of the pipeline network on the basis of an outdated set of definitions.

INGAA supports amending the definitions of “interstate gas pipeline facilities” and “intrastate gas pipeline facilities” in the Pipeline Safety Act to eliminate the jurisdictional distinction between direct sales laterals and other segments of an operator’s interstate natural gas pipeline system. This would make such segments of pipeline subject to

federal safety regulation consistent with the approach taken for the economic regulation of such pipeline facilities.

Direct sales laterals that are not owned by an interstate pipeline would still be regulated by states. This amendment also would have the benefit of permitting the states to concentrate their resources on developing and enforcing integrity management programs for their natural gas distribution lines.

## **CONCLUSION**

Mr. Chairman, thank you once again for inviting me to participate in today's hearing. INGAA has made the reauthorization of the Pipeline Safety Act a top legislative priority for 2006, and we want to work with you and the Subcommittee to move a bill forward as soon as possible. Please let us know if you have any additional questions, or need additional information.

#### Witness Contact Information:

Jeryl L. Mohn  
Senior Vice President, Operations and Engineering  
Panhandle Energy  
5444 Westheimer Road  
Houston, Texas 77056  
713-989-7410

#### INGAA Contact Information

Martin E. Edwards III  
Vice President, Legislative Affairs  
Interstate Natural Gas Association of America  
10 G Street, NE, Suite 700  
Washington, DC 20002  
202-216-5910

#### Summary of Testimony

INGAA appreciates the opportunity to testify on reauthorization of the Pipeline Safety Act. We want to provide the Subcommittee with some background on the natural gas pipeline industry and discuss the progress being made with the Integrity Management Program that was a part of the 2002 reauthorization. In general, INGAA believes the Integrity Management Program is working well in meeting the intent of Congress to reduce risks to the public. Our recommendations for legislation to reauthorize the Act in 2006 include:

- Five-year reauthorization.
- Re-examination of the seven-year reassessment interval that was part of the gas integrity management requirement in the 2002 legislation. We recommend a reassessment interval based on scientific and/or engineering criteria. At a minimum, the baseline assessment/reassessment overlap in years 2010 through 2012 should be eliminated.
- Incentives to further improve state damage prevention programs nationwide.
- Amend the definition of “direct sales lateral” pipelines in the Pipeline Safety Act to make those owned by interstate pipelines jurisdictional to federal, rather than state, oversight.